V. COMPREHENSIVE PROGRAM PROPOSALS

This section presents the six comprehensive program proposals received from parties participating in the Renewables Working Group. Five of the six comprehensive program proposals present strategies for the implementation of the minimum renewables purchase requirement included in the CPUC's restructuring decision. The sixth proposal is for a surcharge-funded program that distributes renewable production credits on the basis of a competitive bidding process. Section VI of the report presents the two adjunct proposals received by the Working Group.

Each proposal begins with an interpretation of the Commission's goals and a rationale for the particular proposal. An overview and description of the specific proposal is then provided. Finally, each proposal supplies answers to the fifty one implementation questions listed in Section II.

V.1 Proposals With a Minimum Renewables Purchase Requirement

A. Renewables Portfolio Standard

Submitted by the American Wind Energy Association (AWEA), California Biomass Energy Alliance (CBEA), Geothermal Energy Association (GEA), Solar Thermal Energy Alliance (STEA), and the Union of Concerned Scientists (UCS)

1. Interpretation of Commission's Goals and Rationale for Strategy

This proposal interprets the Commission's December 20, 1995 renewable energy policy decision to mean that implementation strategies should maintain pre-April 1994 (i.e., pre-Blue Book) system resource diversity provided by renewable energy resources and increase the level of that diversity over time, thereby providing new markets for renewable energy. This is consistent with existing statutory authority. To meet that goal, the Commission seeks a market-based approach that does not require centralized decision-making or centralized collection and dissemination of funds. The Commission also seeks to avoid placing investor-owned utilities at a competitive disadvantage in the market.

This strategy, which we call a Renewables Portfolio Standard (RPS), meets these goals by placing, as of January 1997, an equal renewables purchase obligation on all retail sellers of electricity under the Commission's jurisdiction and, with legislation, on all retail sellers statewide. The obligation begins somewhat below the 1993 level of renewable energy consumption in California and increases gradually over the next few years. Within these levels, retail sellers also have a solid-fuel biomass energy purchase obligation to preserve the existing resource diversity among renewable resources and the associated benefits. The obligation is market-based because it minimizes the regulatory role to that of certifying Renewable Energy Credits, verifying that retail sellers possess the required number of credits for each reporting period, and imposing a significant penalty for non-compliance on retail sellers that fall short. Retail sellers make all decisions about how to comply. The proposed penalty is sufficiently large to ensure full compliance and minimize the need for enforcement action.

2. Program Overview and Description

a. Concept

This proposal, termed a "Renewables Portfolio Standard" (RPS), is for a minimum purchase requirement of renewable electricity to be applied equally to all retail sellers of electricity under the Commission's jurisdiction and, with legislation, on all retail sellers statewide. The requirement is to be in place as of January 1997. The definition of renewables is limited to wind, solar electric, geothermal, solid fuel biomass, waste-to-energy, and biogas. Any renewables generating facility may use up to 25% fossil fuel on an annual basis and qualify as a renewable generator. Any greater use of fossil fuel results in pro-rating the renewables output in proportion to the renewable resource fuel used.

This proposal is entirely consistent with the Commission's decisions and orders relating to renewable power. It is also consistent with existing statutory requirements in the Public Utilities Code. When implemented, this proposal will maintain production from renewable energy facilities serving the state at a level slightly less than that which existed in 1993 (prior to the issuance of the initial CPUC deregulation order in April 1994), and increase that level gradually over time.

b. Description of the Minimum Purchase Requirement

The RPS is designed to preserve roughly the existing level of renewable energy generation in California by requiring that retail sellers support a minimum of 10% renewable energy (kWh) in their annual sales. The requirement is proposed to increase gradually over time by an amount of renewable energy equivalent to the effective capacity that was set aside for renewables by the Commission in D. 92-04-045. Within the 10% requirement is a 1.8% requirement for electricity generated by solid fuel biomass. The separate technology band for solid fuel biomass reflects the desire to preserve the substantial and unique environmental benefits of this industry which stem from its use of biomass fuel, and its higher cost of electricity generation resulting from the necessity to collect, process, and transport that solid fuel, as well as the high cost of its conversion to electrical energy as compared to gaseous or liquid fuels.

The minimum portfolio requirement starts at a level that is less than the amount of energy which can be delivered by the existing renewable energy industry. Renewable generators will have to compete with one another in order to secure a place in the portfolio, since the size of the portfolio is smaller than the ability of the industry to deliver. As a result, competition will be fostered within the RPS which will keep the cost of renewable electricity low. Within the solid-fuel biomass technology band, competition among biomass-fueled generators will likewise keep the cost of that power as low as possible.

c. Renewable Energy Credits

Compliance with the RPS is achieved through use of marketable "Renewable Energy Credits" (RECs), including a subset of "Biomass Energy Credits" (BECs), which are tradable certificates of proof that one kWh of electricity has been generated by the appropriate renewable-fueled source and sold to an end-user in California. Both types of credits are denominated in kilowatt-hours (kWh) and are a separate product from the power itself. The requirement for RECs can be satisfied by ownership of BECs, but not vice versa. Each credit is proof of actual generation and end-use of renewable resource electricity in California not merely proof of capacity.

The sale of RECs is the mechanism by which revenues are transferred from retail sellers to the most competitive renewables generators to maintain their economic viability. The RECs are owned by the renewables generator and may be bundled for sale along with its power, or RECS and power may be sold separately into their respective markets at prevailing market prices. The exception to this is that, during the fixed-price period of a Standard Offer 4 contract, the RECs created by a renewable-resource generator belong to the contracting utility, and are to be sold for the benefit of the ratepayers.

Basing compliance with the RPS on tradable RECs enables retail sellers to develop least-cost power sales portfolios, since they do not have to purchase renewable-resource power. Rather, they can search out the power portfolio which best meets their customers' needs, and then satisfy their minimum purchase requirement through the purchase of RECs. The trading of RECs also creates a cost-reducing competitive market for renewable power since renewables generators will compete to lower the cost of their generation, and therefore the price of their RECS, to assure that their own power and RECs are purchased. These same principles apply to BECs.

d. Equity, Efficiency, and Feasibility

Since the benefits of renewable power are shared by all Californians, under this proposal, all Californians will share in the incremental cost of the renewable energy generation serving the state. The cost is shared equitably since all retail providers must purchase their fair share of RECs, a fixed percentage of their total kWh sales. In terms of efficiency, this proposal is consistent with the state's efforts to lower the cost of electricity in California. This is a market-based program; agency-administered support of renewables is unlikely to produce results at lower cost. Retail sellers of electricity have the freedom to build least-cost combinations of power and RECs, and renewable-resource generators have an incentive to drive down costs so their own power and RECs will cost less than the competition.

In terms of feasibility, the REC market concept is patterned after the emission-reduction credit trading program of the South Coast Air Quality Management District's RECLAIM (Regional Clean Air Incentives Market) Program, which has been very successful, using both a large number of private transactions and an annual auction of credits. This proposal also follows the pattern of the SO_2 credit-trading program under the federal Clean Air Act, which has also been very successful.

When renewables become competitive with conventional electricity sources on a direct-cost basis, this program self-sunsets. That is, when the price of RECs falls to zero as a result of rising costs of convention-fuel power and the declining costs of renewable power, the portfolio standard will no longer be needed.

e. Reporting and Enforcement

Reporting is straightforward. Each year, retail sellers document and report: (1) their total retail sales in kWh for the previous year; (2) ownership of a sufficient number of generic RECs; and (3) ownership of a sufficient number of biomass RECs (BECs). On a quarterly basis, renewable-resource generators report and certify the number of RECs created as a result of their generation.

Sale of renewable power for end use in California is assumed if the power is sold to an end-user in California, power pools serving California, or retail sellers serving California end-users. At the end of the year, a state agency simply compares the retail sellers' reports with the renewable generators' reports, in much the same manner as the Federal IRS compares taxpayer reports of income and dividends with the 1099 forms filed by the payers of that income and issuers of the dividends.

To provide compliance flexibility to retail sellers, a three-month true-up period is provided at the end of each year during which retail sellers may obtain the required number of RECs or makeup any shortfall. During this period, purchases of RECs can be made from renewable- resource generators that may have unsold RECs, or from retail sellers that have RECs exceeding their requirement. After the true-up period, an automatic penalty for non-compliance is assessed at 6 cents for each REC that the retail seller falls short. This penalty is estimated to be about three times the cost of compliance--high enough to encourage full compliance, yet not so high as to encourage litigation.

3. Implementation Questions

a. What Is the Obligation?

a.1 How is "renewables generation" defined for purposes of qualifying for tradeable "renewable energy credits" (RECs) under this proposed program? Does existing and incremental utility-owned renewable-resource generation qualify for RECS?

Given the Commission's goal of maintaining system diversity, the definition of qualifying renewable resources is limited to those resources (and associated technologies) that bring significant public benefits, including economic, environmental, and price stability benefits and fit several, if not all, of the following criteria: (i) are not technologically mature; (ii) are not fully commercialized, i.e., limited market share; (iii) have significant development potential; and (iv) may have difficulty competing in short-term, price-focused markets. The resources that fit these criteria are: biomass (including solid waste biomass, solid waste-to-energy facilities, landfill gas, and anaerobic digester gas); geothermal; solar (including solar thermal electric and photovoltaics); and wind.

The only renewable resource that is excluded from qualification for RECs based on these criteria is hydropower. Hydro was separately addressed by the Commission's December 20, 1995 Decision. Hydro brings some public benefits in avoiding air emissions and wastes from conventional power plants, and some hydro plants (especially those with high environmental mitigation costs) may have difficulty competing in dry years. However, hydro is technologically mature, is fully commercialized (representing a significant share of the California energy market), and has limited development potential. In addition, including hydro in the RPS program would create several practical problems: (a) output from the large Northwest base of hydro could potentially be rerouted into the California market and capture the market created by the RPS; (b) the large year-to-year fluctuations in hydro output would make it difficult for retail suppliers to meet a fixed standard each year and at the same time provide a predictable market for renewables; and (c) many hydro facilities have more than one use and have obtained government subsidies. Therefore, it may be difficult to avoid cross-subsidizing irrigation, recreation, flood control, etc., through payments to hydro via the RPS.

Those facilities that fit this definition of renewables and are consistent with ownership limitations on distributed generation (see question a.9) can qualify for credits. This also relates to credit allocation (see question c.1).

a.2 What are Renewable Energy Credits? How do they relate to energy portfolio management?

Renewable Energy Credits ("RECs") are central to the RPS. A REC is a tradable certificate of proof that one kilowatt-hour of renewable resource electricity was generated. Thus, RECs are denominated in kilowatt-hours (kWhs). A REC is created when: (1) a qualifying renewable-energy resource generates one kWh of electricity; (2) that kWh is ultimately sold at retail in the state; and (3) a satisfactory verification of (1) and (2) is made.

A REC is a separate product from the renewable power itself. Its purposes are to provide the means for retail sellers to demonstrate achievement of the portfolio standard, and to provide retail sellers with a cost-reducing alternative to achieving the standard compared to reliance solely on power purchases. RECs are also the means by which sufficient funds will be provided to renewable generators so as to make viable the level of renewables generation required by the RPS. Every retail power supplier would be required to possess RECs equivalent to a determined percentage of its total annual kWh sales. Retail sellers make all decisions about how to comply. They can purchase RECs when they purchase renewable power (a "package" of RECs and power), or they can purchase RECs separately either directly from a renewables generator or from the REC market. Thus, retail sellers can decide whether to build a renewable energy facility, purchase renewable power bundled with RECs, or buy credits separately. (Note that, if UDCs are not allowed to own generation, they would not have the option of building/owning renewables.) The REC system provides compliance flexibility and avoids the need to "track electrons."
Under this program, retail sellers make all decisions relating to the type of renewable energy to acquire, the price paid, the contract terms offered, and whether to enter into long-term REC and/or renewable power purchase contracts or to purchase these commodities on the spot market.

A subset of RECs, "Biomass Energy Credits," or BECs, would be created to implement a solid-fuel biomass "technology band." All of the above principles would also apply to BECs.

a.3 How is a diversity of renewables encouraged?

A diversity of renewable resources is encouraged because retail sellers and investors are likely to seek out the most cost-effective technologies and technology applications, thereby taking advantage of the most cost-effective applications of each resource (i.e., the low-cost end of the supply curve for each resource). Because, with the exception of solid fuel biomass, the cost of many renewable technologies (new wind, geothermal, and landfill gas facilities and existing solar thermal electric and solid waste to energy facilities) are in the same competitive range, the market is likely to value a diversity of resources and technologies. This should also encourage niche applications of renewables, such as distributed applications of photovoltaics. In addition, the technology band for solid-fuel biomass resources, which would otherwise have difficulty competing with other renewables, will encourage these resources. Beyond these means, further diversity is encouraged through commercialization programs (see next question).

a.4 Are currently-high-cost technologies or pre-commercial technologies fostered by this *program?*

This strategy does not envision the RPS as a technology commercialization program. Thus, the proposal only includes one technology band for solid-fuel biomass, which has a significant existing base of investment and capacity. However, the RPS helps to close the gap between the cost of pre-commercial technologies and the market price. As a result, technology commercialization program dollars, both state and federal (if invested in the state), will go further.

In addition, to support pre-commercial, very high-cost technologies that have significant potential for cost reduction, this strategy recommends that : (i) RD&D programs be expanded to "RDD&C" programs, to include support for commercialization activities for pre-commercial renewable technologies, and that the funding level be expanded accordingly; (ii) customer-side applications of renewables be supported through energy efficiency programs, and that funding levels be expanded accordingly; and (iii) distributed renewables applications be supported through the pass-through of area-specific T&D benefits as an incentive to customers and third parties to invest in distributed generation. When such technologies become closer to market price (including the value of RECs) as a result of such programs, the technology can compete more successfully in the RPS market, and technology bands could be considered.

a.5 How is renewables self-generation handled? Is self-generated renewable energy eligible for RECs, or for other means of support?

Off-grid renewable self-generation applications would not qualify for RECs for several reasons: off-grid applications are not metered or sold at retail, and thus verification of production would be difficult; and most off-grid self-generation applications are already competitive as compared to T&D line extensions.

Surplus generation that is metered and sold at retail from customer-owned, grid-connected renewable facilities could be eligible for RECs. However, the power produced by these systems for on-site consumption would be administratively difficult to verify for the purpose of qualifying for RECs, which are geared to kWh sold at retail. Thus, this application would be better supported through energy efficiency programs.

Third-party-owned, on-grid generation connected on the customer side of the meter could qualify for RECs, provided the power is sold at retail. Power consumed on-site would be supported through energy efficiency programs.

a.6 How are hybrid fossil-fuel/renewable-fuel facilities handled?

Renewable generators using up to 25% fossil fuel would fully qualify as renewable. For generators using more than 25% fossil fuel, only the renewable-fueled fraction would qualify.

a.7 Does out-of-state generation qualify for RECs? Is it desirable or necessary to protect in-state California renewable energy generators from out-of-state competition? Is it possible?

Out-of-state renewable generation that is sold to California end-users would qualify for RECs. Out-of-state solid-fuel biomass generation, however, would not qualify for BECs. Proponents of this strategy believe that the Commerce Clause of the federal Constitution would prevent the state from limiting qualifying renewable facilities to those located within the state[1] with the possible exception of solid-fuel biomass, which is associated with several benefits (e.g., diverting wastes from in-state landfills and prevention of local air pollution created by open agricultural burning) that may not be fully realized without an in-state requirement for these facilities. The in-state renewable energy industry is likely to fare well in competition with out-of-state resources (provided hydropower is excluded), but an in-state restriction for solid-fuel biomass can ensure that the unique in-state benefits of solid-fuel biomass are fully captured.

a.8 If hydro is included, how are practical issues associated with hydropower handled?

Hydro is not included for the reasons stated in question a.1, above.

a.9 How is utility-owned distributed renewable generation handled? Is it eligible to receive RECs? Does the proposal permit RECs to accrue to distributed or other renewable applications that may involve the cross-subsidization of generation with T&D savings, or vice versa? Does the proposal permit or prohibit distributed or other utility-owned renewable power not sold through the power exchange to receive RECs?

The Commission needs to address the market power, self-dealing, cross-subsidization, and functional unbundling issues associated with UDC ownership of distributed generation before such ownership is allowed. UDC ownership could also be inconsistent with the Commission's requirement that all utility and affiliate power be bought and sold through the Power Exchange. Until such a determination is made, UDC- and utility Genco- and affiliate-owned distributed renewables should not qualify for RECs.

a.10 What is the level for the requirement? How does this level relate to the level of renewables from 1990 to the present? Does the level of the requirement increase over time, and, if so, at what rate?

The overall level of the RPS would be set at approximately 90% of the amount of renewable energy delivered in California in 1993 and would rise 0.2% each year beginning on January 1, 1998, until an additional amount of renewable energy, equivalent to the renewables set-aside of 297.5 MW, as set forth in D. 92-04-045, is achieved. Incorporated in these levels would be a solid-fuel biomass requirement, set at a level approximating 80% of all solid fuel biomass generation delivered in California in 1993. According to data provided by the California Energy Commission (CEC), combined with industry figures for 1993 solid-fuel biomass production (CEC figures are not available for solid-fuel biomass), total renewable energy (as defined above) generated for California use appears to be about 11%. Thus, the overall standard would be set at about 90% of 11%, or 10%. The biomass standard would be set at about 80% of 1993 solid-fuel biomass production, or 1.8%. The 1.8% biomass technology band is included in the overall 10%; the two are not additive. The 10% would rise over time by 0.2% per year, while the 1.8% biomass technology band would not.

These levels are set below 100% to ensure that price competition is achieved at the outset of the

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1 See Kirsten Engel, "The Federal Constitution and State Implementation of Renewables Portfolio Standards: An Analysis of Commerce Clause Issues." Posted on the Renewables Working Group web site (http://www.energy.ca.gov/energy/restructuring).

policy. The year 1993 is chosen because, in 1994, restructuring activities caused considerable uncertainty that contributed to the closure of several renewable facilities. As the requirement rises over time, renewables developers have adequate lead-time such that competition will occur.

Note that the actual percentage requirement will vary depending on the universe of retail sellers covered. If the RPS is applied by the Commission to entities under its jurisdiction, the above figures would translate into a higher starting figure than if the RPS is applied to all retail sellers statewide. Also note that, as growth in end-use sales occurs, this absolute amount of renewables generation required under the standard will rise.

a.11 Describe how, if at all, the compliance obligation adjusts during a transition period.

No transition period is proposed, and none is required because the RPS is based on the purchase of RECs, not on the purchase or ownership of renewable power per se.

a.12 Does the proposal include a uniform requirement for all electric providers, including utilities, on a statewide basis?

Yes. This proposal supports the Commission's stated preference that the obligation apply equally to all retail sellers. Legislation would be required to extend the RPS to municipal utilities, special districts, etc. A uniform requirement is reasonable for two reasons: (1) The benefits of renewables accrue largely to the economy and environment of the entire state; and (2) Setting different levels for each entity, based on its current amount of portfolio diversity, and adjusting those levels yearly to achieve uniformity would be administratively cumbersome.

a.13 What is the time-horizon for the program?

There need be no specific sunset provision, as this policy is inherently self-sunsetting. That is, when market and renewables prices equilibrate, the value of RECs will fall to zero. At such time, suspending the standard could be considered. Cost savings will be achieved through certainty and stability of the standard, which will enable long-term contracts and lower-cost financing (for new projects and for repowering existing projects). The ability to obtain financing will foster competition to provide renewable power at the lowest possible cost. Without policy stability, financing costs (and thus the cost of renewables) will be higher, or renewable energy projects will be unable to obtain financing.

a.14 Is the requirement established on a percentage of megawatts or percentage of megawatt-hours basis?

The requirement, and RECs, are based on kilowatt-hours delivered to ensure that renewables generation has actually occurred, and to serve as an incentive for maximum facility productivity. Environmental benefits from renewable energy occur only with generation of power, not from construction of capacity.

a.15 Does the proposal establish floors for certain technology types? What is the rationale for a technology floor, if proposed?

Yes. As mentioned in the answer to questions a.2 and a.3, a technology band would be established for solid-fuel biomass facilities. The rationale is that these facilities represent a substantial existing capacity base which is associated with a broad array of unique and quantified benefits, including diversion of wastes from landfills, prevention of open agricultural burning, and forest management benefits. Costs of collecting, processing, and transporting solid fuel are unique to solid fuel biomass plants among the renewables. These facilities are having difficulty surviving under current market conditions, and are unlikely to be able to compete successfully with other renewable resources due to these fuel-related costs. Loss of this industry would result in increased uncontrolled agricultural waste burning and associated air pollution, increased volume of wastes to landfills with the associated difficulties of mitigating problems of waste disposal such as methane gas and leachate generation, increased forest wildfire danger, poorer watershed management, and worsened forest health.

As mentioned in the answer to question a.10, the solid-fuel biomass technology band would be set at a level substantially below the level of capacity operating in 1993 (and still less than current operable capacity) to ensure competition among biomass facilities and limit costs associated with this technology band.

b. Where Is the Obligation to Comply?

b.1 On whom is the requirement applied? Is the requirement applied only to entities under the Commission's jurisdiction, or is it applied statewide?

If implemented by the Commission, the requirement would be applied to investor-owned utilities, direct access suppliers, and grid-interconnected self-generators transmitting power to another location. Legislation would be required to apply the standard to municipal and cooperative utilities and special districts. This proposal supports statewide application, but, in the absence of legislation, urges implementation by the Commission by January 1997.

b.2 Are regulated retail providers treated similarly to unregulated retail providers? If not, what are the differences?

The REC purchase obligation applies equally to all retail providers.

b.3 What is the penalty for non-compliance? Should this penalty be interpreted as a cost-cap for the program?

A penalty of 6¢ (indexed to inflation) would be imposed for each REC or BEC that a retail supplier fails to turn in at the end of a three-month "true-up" period following each annual reporting period. This is estimated to be 3-4 times the cost of complying with the program.

This penalty is intended to be high enough to ensure full compliance and to avoid costly enforcement measures. It is modeled after the federal SO_2 allowance trading program, under which an automatic $2,000/ton penalty (indexed to inflation) is imposed for each excess ton of SO_2 produced. SO_2 credits are trading currently at about $150 each, though costs were originally projected to cost between $500 and $1500. A utility that does not comply also has its allowance holdings reduced in the next year by one allowance for each excess ton of sulfur dioxide emitted.[1]

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1 U.S. General Accounting Office. *Air Pollution: Allowance Trading Offers an Opportunity to Reduce Emissions at Less Cost*. GAO/RCED-95-30. December 1994

Because of the high penalty associated with noncompliance under the SO_2 allowance program, which took effect in 1995, the EPA anticipates full compliance and does not expect to take even a single enforcement action.[1] Another similar program is NEPOOL's capacity reserve requirement, under which each participant is fined $105/kW-year for capacity shortfalls. This is well in excess of compliance costs, and has successfully deterred non-compliance (though the fine has been assessed and paid on several occasions).

Thus, the RPS penalty is not intended to act as a cost cap, because it exceeds expected costs. Like the SO_2 program, this policy is intended to be self-enforcing by setting the penalty at a level high enough to ensure that the policy goals are met without resorting to administrative and enforcement measures. In addition, encouraging full compliance with a high penalty will ensure that an active credit market is created and that retail sellers are engaged in thinking about how to incorporate renewables into their resource portfolio at least cost, instead of seeking ways out of the program. On the other hand, the penalty is not so high as to be unduly punitive, and can easily be avoided by purchasing RECs to correct any shortfalls during the true-up period.

Though virtually no penalties are expected to be collected, in the event that a few penalties are incurred, this money could be allocated to the agency that administers RDD&C to help fund the commercialization of emerging renewable energy technologies.

b.4 How is non-compliance determined? Who is responsible for determining non-compliance and for resolving disputes arising from such a determination?

Compliance of retail sellers is determined by demonstrating ownership of sufficient RECs in relation to electricity sales. This could be done through an electronic system as follows. (i) A renewable facility owner generates credits (by generating renewable power) which are posted by the administering agency into an electronic account for that owner, and so forth for all owners. (ii) Retail Seller Z purchases RECs from Owner A. Both sign a form requesting the administering agency to transfer the purchased number of RECs from Owner A's account into Seller Z's account. (iii) At the end of the annual reporting period, the agency informs all retail sellers of their account status and asks retail sellers to document their total kWh retail sales. At the end of the three-month true-up period, the required number of RECs are removed from each retail seller's account and retired. (iv) For retail sellers who have insufficient credits in their accounts, the agency imposes the per-REC penalty.

The administering agency and enforcement actions for non-payment of penalties would vary depending on whether the RPS is applied by the CPUC or applied statewide. If applied by the CPUC, then the CPUC would administer the program (unless it were delegated to the California Energy Commission). Penalties could be imposed on delinquent direct access sellers and self-generator-wheelers as a condition of being licensed by the CPUC to sell in the direct access market, and on utilities through the PBR mechanism. If the RPS were applied statewide via legislation, then the administering agency would be the CEC, and the legislature would authorize the CEC to impose and collect penalties. The Attorney General would handle seriously delinquent accounts and criminal behavior. The CPUC could revoke licenses if retail sellers fail to pay assessed penalties. However, it is emphasized again that enforcement actions will be rare if the

[1] Phone conversation with Joe Kruger, Chief, Energy Efficiency Section, Acid Rain Division, Environmental Protection Agency, Washington, D.C. (May 2, 1996). EPA is in the process of verifying 1995 compliance with the program.

penalty significantly exceeds the cost of compliance, as proposed.

b.5 What provisions add flexibility to compliance, if any?

As indicated in the answer to question b.3, a three-month "true-up" period would be provided to retail sellers. In addition, such sellers could "bank" credits in their REC account for 15 months, i.e., through the true-up period for the following year. Finally, since renewable resources depend on the natural availability of resources, extended true-up periods could be provided to respond to extreme deviations in the expected output of these resources ("force majeure" situations). (Note that, if hydropower is excluded, these fluctuations should not affect the entire REC market, but may affect individual retail sellers who have contracted for RECs from certain facilities.) If credits are unavailable in the market for other reasons (e.g., rapid growth in retail sales), true-up periods could be extended until RECs become available.

b.6 How does the program ensure that the policy and its costs are non-bypassable, such as the CTC or the Public Goods surcharge?

If the program is implemented by the CPUC, then costs would be imposed on a non-bypassable basis by requiring all entities under CPUC jurisdiction to comply with the program. Penalties would be imposed as described in the answer to the previous question.

If implemented statewide via legislation, the program would be applied uniformly to all retail sellers. "Retail electricity supplier" should be defined to mean: "any entity that sells electric power not for resale to an end-user, including but not limited to electricity providers that are affiliates or generating companies of investor-owned utility distribution companies, municipal utilities, cooperative utilities, local governments, special districts, or direct access suppliers." "End-user" should be defined to mean: "an entity located in the State that purchases electricity based on metered use but does not resell electricity based on metered use." These definitions cover all situations, including such unique ones as port authorities and malls. Penalties would be enforced on any entity that fails to comply.

c. How Are Renewable Energy Credits Initially Allocated?

c.1 How are RECs generated from existing renewable facilities (QFs and utility-owned) initially allocated? What impact does the initial allocation have on whether a vigorous market for RECs, characterized by many buyers and sellers, forms?

Existing renewable QF projects will own the RECs they generate, except during the fixed-price period of ISO4 contracts. RECs generated during the fixed-price period will be auctioned off by a marketing agent designated by the CPUC, and proceeds will be applied to reduce the CTC, thus benefitting ratepayers. It is necessary to use a marketing agent with no interest in the REC or power markets so that RECs are auctioned off fairly. Otherwise, utilities will have a market advantage over competing retail sellers by having preferential access to these RECs, potentially at no cost. During the fixed-price period, utilities could certify QF output as RECs and turn them over to the marketing agent. After the fixed-price period, as a result of competition between REC sellers, capacity payments made to QFs under Standard Offer contracts will directly contribute to reducing the cost of RECs, just as will the energy payments made under those contracts.

RECs produced by existing utility-owned renewables facilities will be owned by the utility.

Proceeds from any RECs that are sold would be applied to the CTC, thus benefitting ratepayers. At such time as utility renewables facilities are sold or spun off to an unaffiliated entity, the credit rights will accompany the sale, and should be valued as a part of the sale.
Allocating credits in this way will facilitate the creation of a single market for renewables (including new and existing projects) so that the lowest-cost projects will survive. It will also avoid potential market power situations by creating a large number of REC sellers, which will create a competitive market for RECs. As more retail suppliers enter the California market, the number of REC buyers will also increase.

QFs are entitled to the RECs they generate after the fixed-price period because they took the investment risk, and many are, indeed, now facing that risk. The objective of the RPS is to support the existing level of diversity, thus it makes sense for these projects to own the credits. Because the risk of utility projects is passed through to ratepayers (witness the full-cost recovery through the CTC), RECs generated by utility-owned resources should flow to ratepayers.

c.2 What is the relationship between the allocation of RECs and the CTC or Public Goods Surcharge? Will RECs accrue to technologies, such as on- and off-grid renewables, in a way that would encourage customers to disconnect from the grid or otherwise avoid part or all of the CTC and Public Goods Surcharge?

See answers to previous question and question a.5.

c.3 If customers or ratepayers are initially allocated RECs, how are the credits administered?

See answer to question c.1.

c.4 How would the proposed credit allocation affect negotiations to buy out existing QF contracts? Would it encourage or discourage such buyouts? Would it make buyouts more or less cost-effective to ratepayers?

The proposed REC allocation (to ratepayers during the fixed price period of ISO4 contracts and to QFs thereafter) will neither encourage nor discourage QF contract holders from negotiating contract buyouts. To encourage or discourage buyouts means that one party will be placed in a more favorable negotiating position than the other party. This is not an intended result of the RPS. By keeping both parties neutral, negotiations can and will go forward without regard to the RPS or the value of the RECs. Should the CPUC desire to encourage buyouts, it could do so by establishing a definitive basis for such negotiations between the parties. Creating a "tilted" playing field is not an acceptable solution.

c.5 How does the initial allocation deal with the possibility of windfall profits accruing to individual renewables generators, or types of generators?

Because competition is built into this program (see answer to a.10), and because the initial allocation of RECs creates dozens of REC sellers, a very competitive market for RECs will exist because everyone will want to sell all of their RECs. This proposal significantly minimizes the potential for windfall profits by allocating to ratepayers the RECs generated by QFs during their fixed-price period. We are not aware of any renewable generators that would be profitably sustained at current market prices without RECs. Markets work because they reward the most efficient producers. Therefore, the REC market will work to foster the most cost-competitive renewable energy projects, which will minimize the potential for windfall profits.

c.6 Does the proposal potentially increase the value of utility-owned renewable resources in a way that would encourage their divestiture? If so, how should ratepayer interests be addressed?

While the RECs will increase the value of utility-owned renewable resources, the proposal neither encourages nor discourages divestiture by the utilities because the increased value realized upon a sale would accrue to the ratepayers, not stockholders, per the CPUC's 12/20/95 decision. It is possible that the value of the RECs might encourage utilities with renewable resource assets to retain those assets in order to meet the RPS.

d. How Is the Program Administered?

d.1 What agency certifies the RECs, and what does the certification process entail?

If the RPS is implemented by the CPUC, the CPUC could either (a) handle REC certification, (b) delegate REC certification to the CEC, or (c) contract REC certification out to a neutral third party, perhaps a private entity. If the legislature adopts a statewide program (which is the preference of the proponents of this strategy), the program could be administered by the CEC or contracted out to a neutral third party.

Under the certification process, which would occur quarterly, renewable energy generators would certify their output (certification takes place after generation has occurred) by filling out a form provided by the administering entity. (A certification fee could be charged for the sole purpose of covering reasonable costs of certification.) The form would ask for: the name of the company; identification of the unit (e.g., location or I.D. number); the type of facility (checking off from a menu of options corresponding to the qualifying types of facilities); the amount of power generated and the period in which the power was generated; and who purchased the power from the renewables generator. In some cases, data would be requested to assist in the tracking of where end-use of the power occurs.

As a simplifying measure, qualifying renewable power sold to any purchaser on the following list should automatically lead to certification of the RECs: an end-user located in California; power pools serving California; and specified retail sellers serving end-users in California. Though this simplification does not guarantee that all REC-certifying renewable power is contractually linked to California end-users, it is a reasonable simplifying measure.[1] Potential purchasers of renewable-resource power not on the list, such as wholesalers or aggregators serving more than one state, would not be required to participate in REC certification. REC certification based on power sales to these entities could occur only if a generator can arrange with the purchaser to provide adequate proof that end-use took place in California.

d.2 What mechanisms are proposed for trading of RECs? How do the trading mechanisms relate to the initial allocation of RECs?

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[1] For more detail on this point and related issues, see March 6, 1996, memo from Brent Haddad posted on the Renewables Working Group web site (http://www.energy.ca.gov/energy/restructuring).

Other than auctioning off certain RECs (see answers in section c), no mechanisms are proposed for trading RECs. Bilateral contracts and specialized REC markets can be expected to occur without regulatory intervention, as has taken place in similar markets for tradable permits and obligations (e.g., NOx markets under RECLAIM, and SO2 markets under the Clean Air Act.)

d.3 What mechanisms are proposed for program oversight and mid-course corrections?

The implementing agency can adjust the rules as program experience is gained to increase efficiency and better meet the policy goals. The agency should devise measures such as number of sales, number and distribution of REC purchasers, length of time required to verify RECs, cost of certification, etc., to gauge the success of this policy and help to identify areas for improvement in implementation.

d.4 What agency monitors and enforces compliance with the program, and how is it carried out?

See answers to questions b.3, b.4, b.5, and d.1. Whether the agency is the CPUC, the CEC, or other neutral third party, the same entity should both verify the creation of RECs and verify compliance. This will facilitate the verification of RECs, the tracking of RECs, and enforcement on retail sellers. It should also improve administrative efficiency.

e. Cost-Related Issues

e.1 What are the costs associated with the program, and who pays?

It is acknowledged that the cost of renewable power is above current marginal-cost market prices, since that market is dominated by inexpensive natural gas-fueled generators. It is not, however, possible to state what the price of electric generation will be in a restructured electric industry in which the market price reflects the total cost of generation. Current short-run avoided cost prices do not accurately represent the true cost of electricity, and long-run avoided cost will not be apparent until after the CTC collection period ends. Moreover, even in a truly competitive market, total-cost market prices will not reflect the full value of fuel diversity, environmental costs, and in-state economic benefits without policy measures such as the RPS. Below we show that expected benefits of this proposal outweigh expected costs, even using current marginal-cost prices.

COSTS: Keeping in mind that current market prices do not reflect total long-term costs, back-of-the-envelope estimates can be made using these short-run prices (see attached spreadsheets). If RECs are assumed to sell for 1 cent to 2 cents per kWh above current market prices and solid fuel biomass RECs are assumed to sell for 2 to 3 cents above current market prices, then the first year of the RPS can be estimated to cost between $300 million and $550 million. This is 1.4% - 2.2% of the state's total electric bill ($25 billion), and translates to an added cost of between 68¢ - $1.28 per month for the average California household. Program costs can be expected to decline over time as the current power glut dries up, nuclear plants are paid off, market prices rise, and the prices of renewables fall due to competition, technology and project improvements, greater economies of scale, and production economies. Thus, by 2001, estimated program costs can be expected to decline to between $160 and $330 million per year, even as the level of the standard increases.

Even these, however, are overestimates, because they do not count the proceeds from RECs generated by renewable QFs and sold for the benefit of ratepayers during the fixed-price period of the renewables' ISO4 contracts. It should also be noted that the total cost of diversity provided by renewables under this program will be substantially less than what it has cost over the previous decade as a result of dramatic declines in the cost of renewable technologies and the end of the fixed price periods of ISO4 contracts (in contrast to experience with nuclear technology).

BENEFITS: The benefits that accrue from renewable energy and the associated industries far exceed these costs. These benefits total $829 million - $1.28 billion annually and include: $383-844 million in clean air benefits (using adopted CPUC emissions values); $137 million in fuel diversity benefits; $38 million in wildfire risk reduction benefits; $60 million in landfill diversion benefits; $51 million in local property taxes paid; and a $160 million payroll. (See attached spreadsheets.) Without the RPS, some these in-state benefits would be lost to in-state generators that provide fewer jobs/MW and to out-of-state generators. If fuel price and environmental regulatory risks should materialize, this RPS program could result in even more substantial benefits to the state.

e.2 What cost-containment measures, if any, are provided?

There are several ways in which this policy assures least-cost achievement of the Commission's renewables policy goals. Cost savings are first achieved because the certainty and stability of the RPS policy will enable long-term contracts and financing for the renewable power industry, which will, in turn, lower renewable power costs. Least-cost compliance is encouraged through the compliance flexibility provided to retail sellers, who can compare the cost of owning a renewables facility to the cost of a REC/renewable power purchase package and to secondary-market RECs. Finally, since retail suppliers will be looking to improve their competition position in the market, and since all must meet the standard, each supplier will have an interest in driving down the cost of renewables, perhaps by lending their own financial resources to a renewables project, by seeking out least-cost renewables applications, or by entering into long-term purchasing commitments. This fosters a "competitive dynamic" that is not achieved with policies that involve direct subsidies to renewable generators without involving the rest of the electric industry.

Cost containment is provided by setting the standard at a level whose costs can be predicted within reasonable bounds given the benefits provided. There are generally no conditions under which standards (e.g., building codes, safety requirements, etc.) can be avoided. This is because loopholes could be created that might undermine the standard, and because it complicates enforcement. An overall dollar cap is infeasible with a market standard since there is no central source of funding.

e.3 If the program utilizes floors for certain technology types, what are the implications in terms of costs and benefits?

See answer to question e.1.

e.4 Will implementation of the program lead to cost-shifting between consumer groups or regions of the state?

The RPS is to be applied to all retail sellers, hence all consumers, equally. However, applying the RPS policy on a uniform basis could lead to cost-shifting from those utility customers who are currently supporting a high level of renewables (PG&E, SCE and some municipal customers) to those utility customers who are supporting lower levels of renewables (SDG&E and some municipal customers). Specifically, those customers supporting a renewables portfolio in excess of the required percentage of their power sales will have an opportunity to reduce their renewables costs, while others will be required to increase their investment to the required level through acquisition of RECs. Though this could cause some near-term rate impacts, a uniform standard can be justified by the fact that: (a) many of the benefits of renewables accrue statewide, and those customers who have not paid for these benefits in the past have to some extent been "free riders" for the past decade; (b) the cost of renewable energy has declined dramatically and will be substantially less than what has been paid for renewables in the past; and (c) it would be administratively cumbersome to transition from a non-uniform standard to a uniform one.

e.5 How is competition within and between renewable technologies encouraged? Between existing renewables facilities and potential new facilities encouraged?

See answers to questions a.10, a.15, c.1, and e.2.

e.6 What implications, if any, does the proposal have in defining the roles of the UDC and of competitive suppliers of electricity?

No implications. The proposal will not encourage any change in the role of the UDC other than what is envisioned in the restructuring decision.

e.7 What is the consistency of this proposal in relation to cost-related guidance provided by the CPUC roadmap?

If this proposal causes some rate impacts for utilities that currently would not meet the RPS, the Commission may have to accommodate such impacts as necessary to implement its renewables policy.

f. How Does the Program Fit with Other Aspects of Restructuring?

f.1 Is the program compatible with the existence of an ISO? A Power Exchange? A direct access market? Is the proposal consistent with the Commission's vision of the role of the Power Exchange and ISO?

Yes.

f.2 Is the proposal dependent in any way on the Power Exchange or ISO? Is so, are any additional protocols necessary?

No, the proposal does not rely on the Power Exchange or ISO for implementation, and no protocols are necessary specifically to implement the RPS policy. However, rules to accommodate renewables, especially intermittent renewables (e.g., in Power Exchange bidding rules) will facilitate least-cost compliance by reducing artificial market barriers.

f.3 Does the proposal involve conflicts of interest between distribution and competitive retail services? If so, how are they resolved?

No, the UDC is treated the same as all retail sellers. The Commission needs to decide whether UDCs will be allowed to own distributed generation, which may involve conflicts of interest between distribution and competitive retail services.

f.4 How does the program avoid conflicts of jurisdiction between state and federal levels?

The RPS avoids state/federal jurisdictional conflicts by applying the standard to retail sellers, which are clearly under the state's jurisdiction (as opposed to wholesale generators and power pools).[1]

f.5 What is the relationship between the proposal and direct access and "green marketing"?

By developing a renewables base and a solvent renewable energy industry, and by addressing "free rider" problems by spreading the cost of a minimum level of renewables over all consumers, individual consumers are more likely to have the opportunity to support a larger fraction of renewables through their choice of supplier because those suppliers will exist. In addition, the renewables industry will be healthy enough to engage in green marketing, which will entail high transaction costs in reaching prospective customers. Green marketers will also have greater flexibility to achieve their advertised green portfolio targets. The RPS policy will help to reduce the cost of renewables, which will make them more attractive to consumers and retail sellers.

Green marketing could involve bundling RECs with the power sold, so that customers desiring green power may, in effect, retire the RECs, thereby contributing to a higher amount of renewables in the overall resource mix of the state. (Also see section f.8.ii on consumer protection and education.)

f.6 What is the relationship between the proposal and PBR? Does the proposal place RECs under PBR, or exclude RECs from PBR?

There is no explicit relationship between the RPS policy, RECs and PBR. However, as for any other utility cost, PBR can be used to reward utilities for efficiently acquiring RECs or penalize them for inefficiency.

f.7 Does the program create any potential market power problems involving the generation market or RECs?

The allocation of RECs proposed in section c.1 eliminates the potential for market power problems by creating dozens of REC sellers. There are currently a substantial number of renewable generators, with no one or two individual companies possessing a significant share of renewables capacity. Market power problems could exist on the REC purchase side, however, if the three IOUs are the only purchasers of RECs, especially in the first years of direct access. Expanding the RPS, by legislative action, to all retail sellers in the state will alleviate this market power possibility.

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1 See Scott Hempling and Nancy Rader, "State Implementation of Renewables Portfolio Standards: A Review of Federal Law Issues" (January 1996). This paper is posted on the Renewables Working Group web site.

f.8 Does the proposal relate to any consumer protection or consumer education efforts?

i. Rules for new entrants. Compliance with this policy should be a condition of selling power at the retail level. Ideally, all retail suppliers should be licensed, so that such licenses can be revoked in the event of noncompliance or fraud relating to this policy (e.g., false REC certification) and other policies.

ii. Consumer protection and education. No consumer protection efforts should be necessary with this program, but consumer education and green marketing could be fostered through REC certification and "green disclosure" requirements. Retail suppliers should be required to disclose the fraction of energy in their resource portfolio that is supported by RECs (the minimum fraction being that required by the RPS). In addition, retail sellers could be required to provide statements regarding price stability or price risks associated with their resource portfolio which would indicate the value of a higher fraction of renewable energy. This will help to reduce the transaction costs associated with green marketing that are likely to hinder these efforts, and will also assure "green" consumers that they are, in fact, purchasing renewable energy. Retail sellers should be required to file this information with the CPUC or CEC, which would then be made available to the public. Green marketers would have the option of disclosing the information directly to consumers in their bills and advertising materials. This information will also ward against the possibility of consumers unwittingly purchasing "green electricity" that only subsidizes other consumers in meeting the standard, i.e., marketers that advertise themselves as exceeding the standard, but who sell the RECs associated with that excess, thereby not increasing overall green power.

f.9 How, if at all, does the proposal relate to RD&D programs funded by the Public Goods Charge?

This proposal recommends that RD&D programs be expanded in scope and funding to cover the commercialization of technologies that are beyond the RD&D stage, but that are not yet cost-competitive with other renewables yet have significant potential for cost declines (e.g., photovoltaics). Also see question a.4.

f.10 How, if at all, does the proposal relate to energy efficiency programs funded by the Public Goods Charge?

This proposal recommends that DSM programs recognize customer-side renewable energy applications as DSM measures. In addition, this proposal recommends that energy efficiency funds be expanded to cover the commercialization of demand-side renewables, such as solar thermal hot water systems and rooftop self-generation PV systems.

f.11 How does this proposal affect the CEQA compliance work recently initiated by the CPUC?

The CEQA review should consider a scenario which does not include the RPS policy, so that the environmental impacts of potentially reduced renewables production can be measured. In addition, the positive environmental impacts associated with different levels of an RPS should be examined. See also response to question a.15.

g. Legislative Requirements

g.1 Can the CPUC implement this proposal by itself, or is legislation required? What is the status of entities not under CPUC jurisdiction in this program? What would the legislative requirement be?

See answer to b.1 above.

g.2 What steps are needed to implement the program, and how long would it take? How does this implementation timing relate to the CPUC's 1998 implementation goal?

The CPUC's 1998 implementation goal must be moved up to January 1997 given the vulnerability of many existing renewable energy projects, and thus the diversity of the state's electricity portfolio. Ideally, enabling legislation would be adopted in this legislative session, so that statewide implementation can begin by January 1, 1997. However, the CPUC must be prepared to implement this program beginning 1-1-97 if the legislature and governor do not act by the summer of 1996. Given the thought that has gone into this program, as reflected in this proposed strategy, it should be possible to have the program in place by January 1997. The CPUC need only flesh out the above items, which should be relatively straight-forward.

6. Positions of the Parties in Favor/Neutral/Oppose

Comments of the CPUC's Division of Ratepayer Advocates, the Utility Consumers Action Network, and the Independent Power Providers

[114 Words]

DRA supports this proposal if and only if the following are included:

1. The overall renewable non-compliance penalty or fee is 2.5 ¢/kWh ($1998), based on the BRPU increment of renewable over non-renewable second prices.

2. The proposed biomass non-compliance penalty or fee is reduced to 3.5 c/kWh ($1998) in year four of the program.

3. RECs for post-fixed-price QFs become tradable when the contract is bought out. RECs for existing UDC-owned resources accrue to the UDC when the UDC agrees to divestiture or spin-off.

4. ISO treats intermittent renewables as "must run." The price paid to intermittent renewables reflects the cost of maintaining associated reserve capacity.

5. "Emerging" technologies can obtain biomass credits.

Comments of the Surcharge/Production Credit Proposers

I. Fails to define costs: Customers may pay over a Billion dollars/year in over market costs for this program with scheduled increases **(cost calculations to follow).** This program has no cost cap.
II. Requires utilities buy power outside of pool: (See also Comment #3 - IEP Proposal).
III. Ignores CPUC implementation schedule: Is effective January 1, 1997.
IV. Fails to focus on public policy goals: This program, inadequately addresses environmental improvement, new technologies, will probably increase costs, and requires complex administrative processes.
V. Disincents QF contract restructuring: Renewables, immune from market pressure, will maintain current contracts.

Comments of Orange County, Sonoma County, the City of Sacramento, NEO Corporation

We oppose this proposal because it gives a subsidy to existing facilities that are already favored with Standard Offer Contracts. When developers built the plants, they evaluated the risks and rewards. Ratepayers should not be forced to continue subsidizing them. These facilities are free to seek other financial support such as grants, tax credits and vendor participation. This proposal is a BRPU selection process. We vigorously oppose tiers or set asides for technologies. Competition should be market driven through an unencumbered bid process.

Comments of Los Angeles Department of Water and Power (LADWP)

Procurement of renewable resources should be the responsibility of some state entity for the state power pool and the above-market costs of compliance should be borne uniformly by all customers served by the UDC on a non-bypassable basis. Rather than having many entities responsible for procurement of renewables, having one entity responsible for the state's procurement of renewables will minimize the compliance transaction costs. The level and diversity of renewable resource mix should be established by the legislature which would determine the appropriateness of establishing set asides for certain renewable resources. The renewables program should be reviewed every five years.

Comments of Southern California Edision

[131 Words]

This proposal lets both existing and new projects compete to meet its requirement. However, it has a potentially high cost that is unknown since no one can predict the cost of the renewable energy credits. It does have a 6 cent per kwh penalty for non-compliance which means that customers could be paying up to a 6 cent premium for renewable energy.

This proposal also assigns the value of renewable energy credits from existing projects under standard offer contracts to the project developer, not the ratepayers. This provides an additional subsidy to projects which have already been subsidized by IOU ratepayers.

This proposal has a separate standard for biomass which drives up the program cost, makes administration more difficult, and subsidizes forestry and agricultural interests at the expense of electric customers.

Comments of CALSEIA/SEIA/CEC/ETDD

[124 Words]

SUPPORT WITH MODIFICATIONS
Diversity and New Resources: By sizing portfolio below renewables generation peak and requiring all technologies, except solid fuel biomass, to compete based solely on price, proposal ensures that existing renewables are heavily favored. Thus, proposal will not increase diversity or enable new technologies to become commercialized. Will only maintain the status quo. Requires additional bands, as with biomass, for emerging technologies not currently able to compete with existing wind and geothermal plants (see CALSEIA proposal).
Credit Price Cap: Imbalance between RECs supply and demand could cause credit prices to escalate. Reasonable caps for RECs and BECs could be imposed (see CALSEIA proposal). Relatively few buyers and sellers of RECs make imperfect market. Greater degree of extemal control to provide orderly market is likely result.

Comments of the California Integrated Waste Management Board

SUPPORT: This proposal seeks to preserve most of the 1993 level of renewable generation in California. It allows for some growth in renewable generation. It recognizes the unique environmental benefits of biomass through a separate band.

Because available renewable generation will exceed the purchase requirement, bidders will have an economic incentive to reduce costs to secure coverage under the standard. This will reduce the gap between the WEPEX and renewables prices. The long-term result will be price competition between all generators.

There is no cost cap and the size of the non-compliance penalty is large enough to assure compliance.

Comments of Don Augenstein

The "Renewables Portfolio Standard" proposal by AWEA et. al. involving RECs appears well thought-out. Its prescribed approach should result in a high degree of competition as desired by the CPUC. I believe the banding of solid fueled biomass facilities for their environmental benefits is a good idea. To the extent I have considered implications to this point, it's very good.

Comments of SoCAL Gas

They propose a renewables energy target based on 96% of the 1993 percent of the state's renewable energy (10.4%), excluding hydro. This translates into a target of 10% that is expected to grow by 0.2% per year until the percentage increases by an additional 300 MW to match the level set forth in D. 92-04-045. Without respect to cost, the proposal wants to implement the anticipated results of the BRPU process. The punitive 6 cents per kWh for noncompliance is not justified and the program lacks any sunset provisions. The program seeks to grow a renewables portfolio without respect to cost.

Comments of SDG&E

Oppose:

* No cost limitation. Proponents contemplate costs exceeding $500 million annually statewide. Proposed penalty could increase total cost to $1.5 billion
* Primarily subsidizes already-subsidized existing projects instead of new develcepment.
* Unequal cost burden on consumers. Penalizes SDG&E's customers for not having previously been subjected to more high-priced ISO4s.
* Inconsistent with electric restructuring; mandates distribution companies to maintain resource portfolio instead of relying on the competitive market.
* High cost penalty structure proposed to force compliance rather than fostering cooperative/voluntary compliance .
* A competitive renewable trading market likely will take significantly longer than two years to develop.
* Administratively burdensome and complex.

Comments of IEP

- Requires legislation to fully implement.
- Increases regulatory burden (and costs) for non-utility retail providers including self-geneators (e.g. schools, hospitals, governmental entities, business entities) and supply aggregators.
- Places UDC's owning renewables (either via contact or through ownership) in a competitive advantage (i.e. monopsony position) vis-a-vie other, smaller retail providers seeking to enter the
- market for generation services.
- Policing and enforcement mechanisms to ensure compliance are unclear; relies on unnamed state agency and may require formation of new state agency.
- Represents a reduction in level of renewables attained through existing state policy.

Comments of the Union of Concerned Scientists

Support.
Good points: Increment in MRPR in line with policy goals of BRPU for adding resource diversification. Exclusion of hydro avoids subsidization of a mature, fully commercialized

technology and problems with annual variability. Significant 6 cents/kWh non-compliance penalty encourages compliance, does not create significant penalty fund for administration. Biomass band ensures a diversity of renewables and values unique environmental and social attributes. Broad renewables industry support.